ANNUAL REPORT: 2000

PACIFIC NORTHERN GAS LTD.

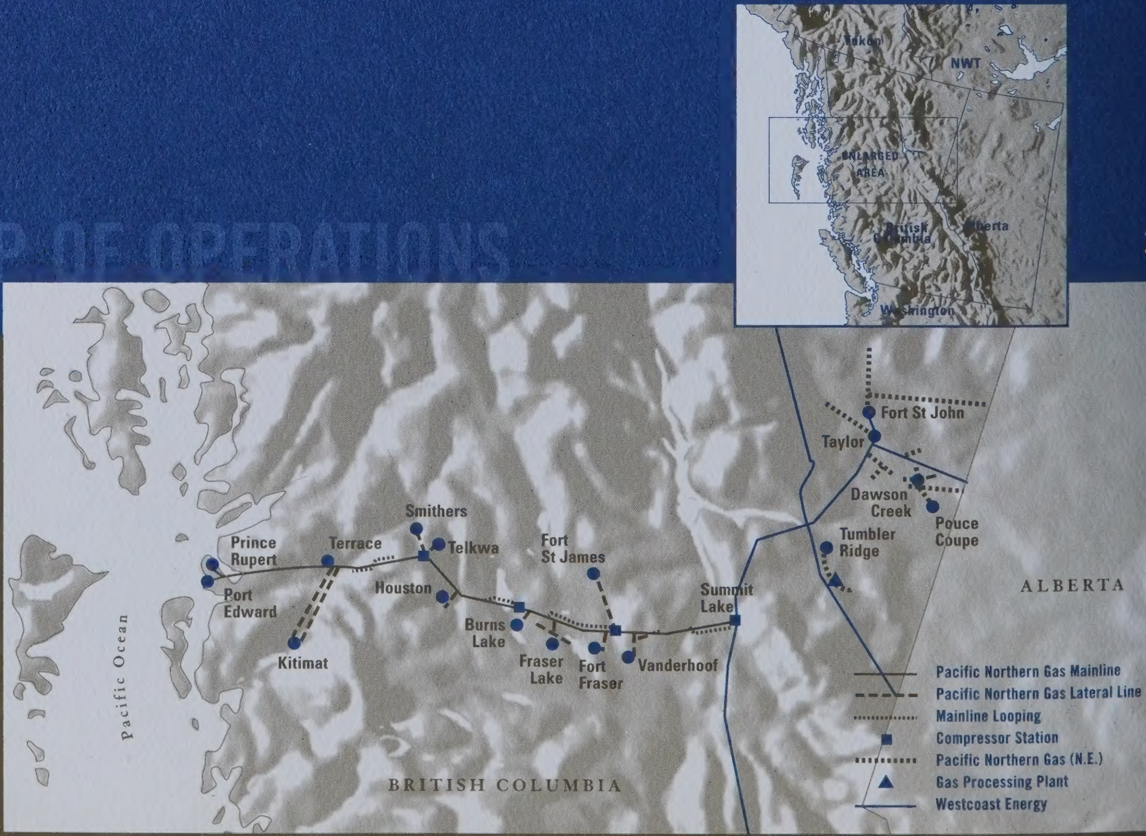
Pacific Northern Gas Ltd. delivers natural gas to customers in west-central British Columbia, and through its subsidiary, Pacific Northern Gas (N.E.) Ltd., to customers in the province's northeast.

Pacific Northern's transmission pipeline is connected to the Westcoast Energy Inc. system near Summit Lake, British Columbia and extends 365 miles to the west coast. Service is provided to some 24 thousand customers including a number of large industrial operations. In addition, propane vapour distribution is provided in the community of Granisle.

Pacific Northern Gas (N.E.) systems serve some 16 thousand customers in the Fort St. John, Dawson Creek and Tumbler Ridge areas. Gas supply is received at a number of locations within the Fort St. John service area. In the Dawson Creek area the Company's transmission pipeline is used to transport gas from the Westcoast Energy Inc. system. In Tumbler Ridge the Company operates its own gas processing plant.

Pacific Northern's head office is located in Vancouver, British Columbia. Customer care and administrative functions are supported from a regional centre in Terrace. In addition, personnel responsible for customer service and system construction, operation and maintenance are stationed in nine communities located within the Company's service areas.

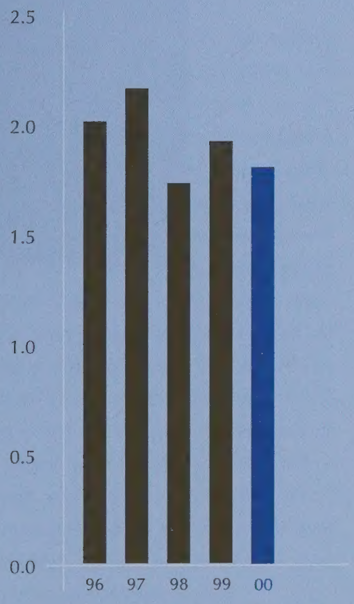
MAP OF OPERATIONS



COMPARATIVE FINANCIAL HIGHLIGHTS

	2000	1999	1998	1997	1996
Total energy delivered (TJ)	**34 771**	42 577	38 787	42 296	38 716
Net income (000)	**$ 6,838**	$ 7,125	$ 6,454	$ 7,926	$ 7,385
Earnings per common share	**1.83**	1.92	1.73	2.16	2.01
Dividends per common share	**0.56**	1.12	1.10	1.00	0.96
Total investment in utility plant (000)	**183,351**	182,917	180,224	177,562	158,239

BUSINESS HIGHLIGHTS



EARNINGS PER COMMON SHARE

- Pacific Northern's net income was $6.8 million in 2000, compared with $7.1 million in 1999.
- After providing for preferred share dividends, earnings per common share in 2000 were $1.83 compared with $1.92 in 1999. In response to business conditions, no common share dividends were paid during the third and fourth quarters of 2000.
- Gas deliveries during the year totalled 34.8 petajoules, compared with 42.6 petajoules in 1999.
- Additions to property, plant and equipment totalled $7.9 million in 2000, compared with $10.4 million in 1999.
- Upgrades to the Company's system included construction of a tunnel to permit relocation of a portion of the mainline between Terrace and Prince Rupert.
- A customer care centre was opened in Terrace, thereby permitting closure of ten community service offices and significant reductions in labour requirements and operating costs. Additional savings were realized through downsizing and consolidation of responsibilities of operations and maintenance personnel.

The year 2000 presented serious challenges for Pacific Northern Gas and disappointments for its stakeholders.

While net income declined only modestly from recent years, our financial performance does not fully reflect the challenges which were experienced during the year or the challenges we will face in the future. These arose as a result of: the Company's largest customer, Methanex Corporation, suspending operations at its Kitimat petrochemical complex; and, unprecedented increases in natural gas prices.

In response to events in 2000, we significantly reorganized our operations. The Company is now better positioned to address the ongoing challenges it faces.

Suspension of Methanol and Ammonia Production in Kitimat

For some time, the Company has been engaged in discussions with Methanex concerning long-term extensions of the Methanex transportation contracts which expire between 2002 and 2009. By early 2000, however, it became evident that rising Western Canadian natural gas prices were jeopardizing the viability of natural gas feedstock-based methanol and ammonia production at the Kitimat complex.

In May 2000, Methanex announced that effective July 1, 2000, it would suspend operations in Kitimat for a period of one year. Prior and subsequent to this announcement, Pacific Northern participated in discussions with Methanex and the Provincial Government aimed at restructuring costs to assure the plant's ongoing viability. Pacific Northern indicated it could offer, subject to the extension of terms of the transportation contracts, a very substantial reduction in tolls. Ultimately, however, rising gas prices completely overshadowed the issue of pipeline tolls, and it now appears that continuing sale into the globally competitive methanol marketplace cannot be justified. It is not clear whether the situation will change, and the Company is therefore assuming the production suspension may be permanent.

Gas Pricing and Our Competitive Position

As I have indicated, Western Canadian natural gas prices, and for that matter natural gas prices throughout North America, have increased dramatically. The rise has been rapid and unprecedented. By way of example, using the price of gas purchased by the Company on behalf of its residential and small commercial customers, average costs per gigajoule were under \$3.00 in 1998 versus almost \$6.00 in 2000. While the impact was partially offset by the

Roy G. Dyce, President and CEO

Company's risk management plan, gas prices rose to over $19.00 per gigajoule in December 2000. There appears to be a general consensus that for the foreseeable future, strong demand for Western Canadian natural gas will maintain price levels well above those of the mid to late-1990s.

Despite current pricing, natural gas remains an attractive fuel for our customers' heating requirements. Among the convenient energy alternatives (electricity, oil and propane), electricity is our primary competitor. As a matter of Provincial Government policy, the price of electricity to customers in our service area has been frozen since 1993.

At Pacific Northern, we believe the impacts of higher gas prices will include minor reductions in use per account resulting from lowered thermostats and more careful energy management by our customers. Also, there will be some displacement of natural gas by wood burning. The negative impacts of wood burning on air quality have already raised the concern of local officials in some of our service area communities. Overall, natural gas will continue to be the fuel of choice with respect to convenience and environmental benefit, and I remain confident of our position with existing customers and in the new home construction market.

Financial Issues and Dividends

Like most regulated utilities, Pacific Northern finances its capital investments through a combination of debt and equity. As is typical, the Company is required by its regulator to maintain a relatively high debt to equity ratio. This strategy serves to minimize the costs which must be recovered from customers' rates.

Pacific Northern's rates are designed to recover capital investment over the useful life of its facilities. For a large portion of these, including the majority of transmission and distribution assets, the depreciation period is 40 years. This is a longer period than the term of the Company's long-term debenture financing. As a result, rates do not fully recover borrowed principal over the term of a debenture issue, and remaining principal must be refinanced when the debenture matures.

The uncertainty relating to deliveries to Methanex as well as natural gas price increases have made it difficult for the Company to raise capital on acceptable terms. Furthermore, the Company has been required by its lender to reduce its operating line, and will also be required to make a scheduled $12 million payment in July 2002 on its Series 2002 Debentures.

In response to this situation the Board developed strategies to preserve capital and reduce operating costs. The first of these measures was the suspension of dividends on the Company's common shares. Further, current and planned capital expenditures have been cut substantially, operations have been reorganized to reduce staffing, and an application has been submitted to the British Columbia Utilities Commission to seek regulatory relief which will assist the Company in addressing its changed business circumstances.

Reorganization of the Company's Operations

The most visible effect of the Company's cost reduction measures is the closure of our local customer service offices. In response to rising gas prices and the need to reduce operating costs, the decision was made to replace these offices with a more cost effective centralized facility. Ten offices were closed and replaced with a customer care centre in Terrace. Our customers now have toll-free telephone access to the care centre for billing enquiries and service requests. The Banner® customer interface system, implemented in mid-1999, is very well suited to our new, centralized operation. Service requests are transferred back to appropriate personnel, who remain at key locations throughout our service areas.

Other aspects of the Company's reorganization include downsizing of the Vancouver office, reduction of compressor operations and staffing, and consolidation of transmission and distribution service and construction responsibilities.

The net impact of the reorganization has been a staff reduction of over 40 percent. Savings will also be achieved with respect to office leases and operating costs. The cost reductions that are achieved from the reorganization will be passed on to our customers, and serve to assist in maximizing the competitiveness of natural gas relative to energy alternatives.

The Years Ahead

At Pacific Northern we have responded to serious difficulties during the past year. We have made significant changes in the way we do business and will continue to work to resolve the financial challenges facing the Company. We have confidence in our well maintained transmission and distribution system, in the organization that is in place to operate and maintain it, and in our ability to continue to provide quality customer service.

The corridor we serve has great potential for economic growth including value added forestry, natural gas and oil production from offshore as well as established reserves, primary metals production, tourism and inter-continental goods movements. Our business will benefit from future developments in any or all of these areas.

In closing, I wish to acknowledge the dedication of our employees. They have faced considerable uncertainty and a great deal of change in the past year, and have responded to the challenges with commitment, strength and creativity. Also, my sincere thanks to the Board of Directors for the guidance they have provided and to our shareholders for their commitment and confidence.

Roy G. Dyce
President and
Chief Executive Officer

Vancouver, Canada
February 26, 2001

Financial Performance

Pacific Northern's net income in 2000 was $6.8 million, compared with $7.1 million in 1999. After providing for preferred share dividends, earnings per common share were $1.83 compared with $1.92 in the previous year. Dividends paid to common shareholders were $0.56 per share compared to $1.12 in 1999. Dividends were not paid in the third and fourth quarters of 2000.

The primary factors resulting in the decrease in net income were higher short-term interest expense and a reduction in the recognition of income tax savings from redemptions of junior preferred shares.

During 2000, junior preferred shares were redeemed in the amount of $1.7 million. The redemption arises from the application of losses acquired in 1996, which generated income tax savings of $0.2 million in 2000.

The fourth quarter results in 2000, as summarized in the table below, were lower than those experienced in the fourth quarter of 1999 primarily due to the non-availability of income tax savings from redemptions of junior preferred shares, which were fully redeemed in the first quarter of 2000. The redemptions generated fourth quarter earnings of $0.03 per common share in 1999 versus nil in the fourth quarter of 2000. Application of these losses resulted in earnings per common share of $0.11 in 1999 compared to $0.05 in 2000.

Natural Gas Deliveries

Natural gas deliveries totalled 34.8 petajoules* compared with 42.6 petajoules in 1999. The decrease is attributable to a 9.7 petajoule reduction in deliveries to Methanex resulting from suspension of methanol production in its Kitimat plant. In all service areas, deliveries to most other customer groups were at levels similar to 1999. Exceptions, which in aggregate accounted for a 1.1 petajoule increase, were deliveries for electric power generation in the Prince Rupert area and to a natural gas producer in Tumbler Ridge.

Natural Gas Supply

All of the Company's residential customers, most of its commercial customers and a number of its industrial customers continue to rely on the Company for arrangement of their natural gas supply, and pay tariffs which include gas supply and service costs. As the cost of gas is normally passed through to customers in rates and subsequent rate adjustments, after approval by the British Columbia Utilities

**The joule is a metric energy measurement unit. one gigajoule (GJ) is equivalent to 0.94782 million British thermal units. One terajoule (TJ) equals one-thousand GJ. One petajoule (PJ) equals one-million GJ. In volumetric units, 1000 cubic metres is equivalent to 35.301 thousand cubic feet.*

CONSOLIDATED QUARTERLY RESULTS

($ thousand, except for share data)

	2000					1999				
	Mar. 31	June 30	Sept. 30	Dec. 31	Total	Mar. 31	June 30	Sept. 30	Dec. 31	Total
Operating revenues	**32,247**	**18,023**	**25,545**	**39,918**	**115,733**	26,615	15,549	12,289	23,285	77,738
Net income (loss)	**3,698**	**613**	**(53)**	**2,580**	**6,838**	3,224	957	118	2,826	7,125
Earnings (loss) per common share — basic	**1.02**	**0.15**	**(0.04)**	**0.70**	**1.83**	0.89	0.25	–	0.78	1.92
Earnings (loss) per common share — fully diluted	**0.99**	**0.14**	**(0.03)**	**0.69**	**1.79**	0.86	0.25	0.01	0.75	1.87

Commission (the Commission), involvement in gas supply has limited impact on net income. However, increasing natural gas prices in 2000 caused an increase of approximately $7.8 million in the Company's gas cost deferral account and put pressure on the Company's financial resources. The Company was required to utilize its line of credit to finance the under recovery of gas supply costs until approvals could be obtained from the Commission to pass through the higher costs to customers on a more expedited basis.

Pacific Northern's larger customers typically arrange for their own firm gas supplies and contract for transportation service on the Company's system. These customers may also purchase gas from the Company when available supply is surplus to the needs of core market customers, or arrange interruptible transportation service if capacity is available on the system.

All of the Company's gas supply is produced in British Columbia. To meet the requirements of its core market customers, natural gas is purchased under long-term, seasonal and spot contracts. Contracted gas that is surplus to the requirements of these customers in non-peak periods may be sold either on an interruptible basis to industrial customers or off-system.

Natural gas is purchased at prevailing market prices and passed through to customers without any markup by the Company. Variances in gas costs from those included in current retail rates are deferred for subsequent refund to or recovery from customers. A gas supply price risk management plan is used to manage gas supply price volatility through hedging arrangements. The 2000/2001 plan resulted in the hedging of gas supply prices for the 2000/2001 winter period as well as for April to October, 2001. For 2000, approximately 20 percent of gas purchases were hedged, reducing the overall cost of gas by $1.3 million. Note 12 to the Consolidated Financial Statements provides further information as of December 31, 2000 with regard to 2001 gas supply. The prices of gas purchases in 2000 were the highest ever paid by the Company. The risk management plan effectively moderated the overall cost of gas supply during late 2000 and early 2001 when prices were some five times greater than at the previous year end. Decisions on the 2001/2002 plan will be made during the first half of 2001.

Virtually all of the Company's gas supply is comprised of the pooled gas stream available from the Westcoast Energy Inc. transmission pipeline system. This includes all of the supply to the Company's transmission line serving its western service area and approximately 75 percent of the supply for the Fort St. John and Dawson Creek service areas.

In addition to the supply from Westcoast, the Fort St. John system incorporates two supply interconnections with Williams Energy (Canada) Inc.'s West Stoddart Pipeline. In Dawson Creek approximately 24 percent of the required supply is received from a local producer of sweet (pipeline quality) gas at a point where its system intersects Pacific Northern's transmission line. In Tumbler Ridge, all of the gas supply is obtained in the form of raw gas production from a local producer and the Company operates its own gas processing facilities.

A long-term contract with CanWest Gas Supply Inc. accounted for about 85 percent of 2000 purchases. Other supplies included purchases under seasonal and spot arrangements.

Main Extensions and Customer Additions

A total of 428 customers were added to the Company's distribution systems during 2000, virtually unchanged from the 430 additions recorded in 1999. It was the third consecutive year with a marked decline in addi-

tions relative to those which were achieved through the mid-1990s. In part, this is a result of the limited number of candidates remaining for conversion to natural gas in the existing building stock and limited remaining opportunity to extend gas mains into unserviced rural areas. Also, with the exception of the Company's northeastern service area, local economies have been depressed as a result of uncertainty concerning future industrial activity levels and new housing starts have declined to about one-quarter of the level of the mid-1990s. This lower level of customer additions is expected to prevail in the foreseeable future.

Within the revenue requirements applications before the Commission which are discussed below, Pacific Northern has proposed modifications to its main extension and service connection policies and fees. The proposed changes would result in common policies in all service areas. Consistent with Commission guidelines which were issued in 1996, new customers would be required to fully cover costs of service line connections to the distribution system, whereas, for the western distribution system, the current policy requires new customers to contribute only a portion of such costs. Also, in situations where main extensions are required, the proposed modifications would reduce the Company's allowable investment in construction, and would require initial customers to fund the full amount of any shortfall between the Company's allowable investment and total estimated construction costs. The latter change would eliminate the Company's role in financing a portion of main extension costs until all anticipated customers are connected to a new main.

Regulatory Activities

The revenue requirements applications for 2000 for all service areas were settled through negotiations with the customers under alternate dispute resolution processes supervised by staff of the Commission. With respect to the western transmission and distribution systems, agreement was reached to keep delivery costs at 1999 levels. An industrial customer gas deliveries deferral account was agreed upon, under which the difference between actual and forecast margin from deliveries to Methanex, Skeena and Eurocan would be deferred for future recovery. With the closure of the Methanex facility in Kitimat in July and lower than budgeted deliveries to Eurocan during the year, $1.0 million net of income taxes was recorded in the industrial customer margin deferral account in 2000. The Company is seeking Commission approval to collect this amount in 2001 rates.

With respect to the Fort St. John/Dawson Creek and Tumbler Ridge divisions of Pacific Northern Gas (N.E.) Ltd., the 2000 rate application settlements resulted in minor cost reductions compared to what the Company requested the Commission to approve.

Natural gas supply costs increased significantly throughout 2000. The Company applied for and received Commission approval to increase prices to customers as of July 1, 2000 to reflect higher gas costs, resulting in an average 25 percent increase for residential and commercial customers in its western service area. On Septemer 28, 2000, the Company filed its 2001 revenue requirements application for its western service area in conjunction with an application to further increase rates effective October 1, 2000. The Commission approved a portion of the requested rate increases on an interim basis for the October to December 2000 period to further address rising natural gas prices as well as liquidity issues faced by the Company, resulting in an average 10 percent increase for residential and commercial customers.

The Commission approved interim rates effective January 1, 2001, based on the Company's December 18, 2000 revision to its 2001 revenue requirements applications. The revisions reflected the implementation of the final phase of the Company's restructuring plan and rate adjustments to flow through higher gas supply costs based on a gas price forecast dated November 23, 2000. The requested average rate increase

for residential customers in the western distribution area was about 16 percent comparing October 1, 2000 rates to January 1, 2001 applied-for rates. Actual gas prices in January 2001 were approximately 40 percent higher than those forecast in November. The Company sought and obtained Commission approval to increase rates as of February 1, 2001 in its western service area to accelerate the recovery of the recorded balance in its gas supply cost deferral account from three years to one year. The approved rate increase for customers purchasing gas from the Company in its western service area was $1.07 per gigajoule.

The October to December 2000 rate increases and the 2001 revenue requirements application for the western service area will be reviewed at a public hearing in Terrace at the beginning of March 2001. The application is based on the assumption that the Methanex complex will remain closed for the foreseeable future.

As part of its 2000/2001 revenue requirements application, the Company is seeking Commission approval to recover from Methanex its share of unbooked deferred income taxes as well as an increase in the depreciation rate for the remaining life of the existing contracts. These recoveries would amount to $6.1 million and $5.7 million respectively. Approval would assist in positioning the Company to handle the termination of its 44 MMcf per day contract with Methanex as of October 31, 2002. Other contracts with Methanex for 2.0 MMcf per day and 11 MMcf per day expire in October 2003 and October 2009 respectively.

Revenue requirements applications for 2001 were filed for the Pacific Northern Gas (N.E.) Ltd. Fort St. John/Dawson Creek and Tumbler Ridge divisions on December 1, 2000. The applications, which on average may increase residential rates by approximately 32 percent, are being reviewed through a written hearing process which is scheduled for completion in March 2001.

Decisions on all revenue requirements applications are expected to be rendered by the Commission in the second quarter of 2001.

In December 2000, the Commission confirmed that its formula for determining the allowable return on common equity resulted in a 9.25 percent return for a low risk benchmark utility for 2001. The return on common equity for Pacific Northern is determined based on its risk premium relative to the low risk benchmark utility. A return on equity risk premium of 75 basis points applies to the western division and Tumbler Ridge resulting in an allowable return on equity of 10.0 percent for 2001. For the Fort St. John and Dawson Creek service areas the risk premium is 50 basis points for an allowable 9.75 percent return for 2001.

Large Industrial Customers

The Company has firm transportation service and interruptible sales agreements with four of its large industrial customers: Methanex Corporation, Skeena Cellulose Inc, Eurocan Pulp & Paper Co. and Alcan Smelters and Chemicals Ltd. These customers produce commodities which are subject to world commodity price fluctuations. The Company's gas deliveries to these customers have been and may in the future be affected by their ability to continue operations during sustained periods of low commodity prices. The Company delivers gas to its other large industrial customer, BC Hydro, under an interruptible sales agreement for electric power generation at BC Hydro's facility in Prince Rupert.

Methanex shut down its Kitimat methanol plant in July 2000 and indicated the plant would not be operating for "an initial period of twelve months". Prior to the shutdown, Methanex was taking delivery of approximately 60 percent of the volumes of gas delivered by the Company. These deliveries accounted for approximately 27 percent of the Company's operating revenues. Gas deliveries to Methanex are made pursuant to three agreements that expire between 2002 and 2009. The

agreements contain minimum volume provisions, which have the effect of limiting the Company's exposure to fluctuations in gas deliveries to the Kitimat plant. The provisions require Methanex to take delivery of, or in any event pay for, a minimum level of 80 percent of the contracted volumes of gas. The Government of British Columbia guarantees Methanex's performance under the largest contract, which expires in 2002 and covers 77 percent of the total contracted capacity. With the July 2000 shutdown, deliveries to Methanex in 2000 declined to 43 percent of total system deliveries. However, as a result of the minimum payment provisions contained in the contracts with Methanex and due to the large industrial deferral account approved by the regulator during the 2000 alternate dispute resolution, Methanex accounted for 19 percent of operating revenues in 2000.

While world prices of methanol increased significantly during 2000 to over $200 U.S. per tonne, rapidly rising prices of gas delivered to the plant made it apparent that production of methanol from the Kitimat facility for sale into the globally competitive marketplace could not be justified until the gap between the price of methanol and natural gas widened. Although the Company has participated over the past two years in discussions with Methanex and the Provincial Government aimed at restructuring costs to ensure the plant's ongoing viability, a solution has not yet been reached.

The Company's long-term transportation service and sales contract with Skeena Cellulose Inc. matured in 1999 and is now in the second year of an evergreen one-year renewal. Similar transportation contracts with Eurocan Pulp & Paper Co. and Alcan Smelters and Chemicals Ltd. are in effect through 2004. Discussions on possible extensions of these agreements are on hold pending the final outcome of the Methanex situation. During 2000, gas deliveries to these three customers accounted for 21 percent of the Company's total gas deliveries and 12 percent of total operating revenues. BC Hydro's electric generating facility in Prince Rupert has typically been used as a stand-by facility. However, with capacity made available from the Methanex shutdown and with the recent attractive markets for electric power, the Company delivered nearly one petajoule of gas to this facility in 2000.

Engineering

In April the Company initiated a $1.6 million project involving construction of a tunnel for the relocation of an 1100 foot section of its transmission mainline between Terrace and Prince Rupert. The original transmission line in this area was in jeopardy as a result of river bank erosion. The project was completed successfully with the new section of pipe being placed into service in July.

In response to the suspension of operations at the Methanex facility and the resulting reduction in deliveries through the western transmission mainline, compressor stations in Vanderhoof and Smithers were shut down and the Burns Lake compressor is being operated on an intermittent basis as required. In addition, one of the compressor units at the Summit Lake station was modified to meet anticipated future base load and temperature-sensitive peak requirements.

In December, the Company experienced an ice blockage of its transmission line which provides service to Dawson Creek. Many customers in the community experienced a disruption of service. Rerouting of gas permitted restoration of service at a reduced level, and extra crews were assigned to assist customers with relights. Subsequently, the blocked section of pipe was isolated and the problem rectified. Full service to the community was restored within three days after the initial disruption.

During 2001, the Company expects to spend less on capital projects than it has in recent years. No routine mainline improvements are scheduled. The largest project planned for 2001 involves upgrades to

control panels at the Summit Lake compressor station at a cost of approximately $250 thousand. In total, capital expenditures in 2001 are forecast to be $5.8 million, which is approximately 40 percent less than in 2000.

Operations

Significant reorganization of operations was undertaken to bring costs in line with the Company's changed circumstances. A primary focus of the reorganization was on administrative and customer accounting functions. Changes included termination of the acceptance of across-the-counter bill payments and service requests at community offices, and the opening in December of a telephone-based customer care centre in Terrace. As a result of these changes two field offices were closed and staffing was reduced in eight others. Reduction in the work force was partially offset by introduction of six new positions in the customer care centre. The net effect of these changes is forecast to result in a reduction in annual operating costs of some $2.5 million. During 2001, the saving will be partially offset by one-time severance costs of approximately $1.2 million.

2000 marked the first complete year of customer billing using the Banner® customer interface system. Many business process improvements were implemented during the year to exploit the system's capability and to more effectively integrate it into the Company's operations. As well as providing the foundation that assisted in making the transition to centralized customer care, these improvements have led to more timely and accurate information being available to the Company for its daily operations, and responses to customer enquiries.

Opening of the customer care centre has facilitated the consolidation of all routine billing functions into one location. This change will encourage the ongoing development of specialized expertise among staff, and will enhance service levels and efficiency.

In the past the Company had separate groups of construction personnel assigned to the western service area's transmission and distribution systems. Staffing reductions resulted from redeployment of personnel to support both requirements. Other personnel changes included reassignment and consolidation of administrative, technical and engineering support functions. Overall, by early 2001, the Company's labour force had been reduced by over 40 percent to a total of 90 employees.

As a result of reorganization of its operations and labour force, Pacific Northern anticipates reductions in all aspects of the Company's business expenses.

Despite the closing of its customer service offices and the reorganization its labour force, Pacific Northern has retained operations personnel at locations throughout its service areas. These employees are responsible for routine duties such as meter readings and customer service requests, as well as being available to respond in the event of emergency situations.

Operating Activities

Additions to property, plant and equipment totalled $7.9 million in 2000, compared with $10.4 million in 1999. Operating, maintenance and administrative costs totalled $19.3 million, an increase of $0.4 million relative to 1999. In addition to higher costs associated with inflation, the increase reflects the higher prices for fuel gas required to deliver gas to customers.

Liquidity and Capital Resources

The Company's investment activities are financed by cash generated from operations and drawings under its operating line, together with proceeds from the issue of long-term debt and share capital. The uncertainty relating to the Methanex plant and increasing natural gas prices have made it difficult for the Company to raise capital on acceptable terms. As noted above, the future operation of the Methanex plant remains uncertain.

Following the announcement in May 2000 of the planned Methanex shutdown, the Dominion Bond Rating Service reduced the rating of the Company's long-term debt and preferred shares from BBB to BB+ and from Pfd-3 to Pfd-4 (high), respectively. Among the items reflected in the decision were concerns about the long-term future of Methanex and Skeena Cellulose. In July, the Canadian Bond Rating Service reduced the rating of the Company's long-term debt and preferred shares from BBB to BB and from P-3 to P-4, respectively.

The Company has a secured demand line of credit that provides funds for general corporate and working capital requirements. In October, the Company and its operating lender agreed to a reduction in the demand line of credit from $35 million to $30 million, and a re-documentation of the facility.

The Company's capital expenditure program for 2001 will be financed by cash from operations and the available line of credit.

The unprecedented increases in natural gas prices in 2000 have resulted in unexpected demands on the Company's line of credit and cash resources. The Company anticipates that these demands will ease as the winter heating season draws to a close with the result that the utilization of the line of credit is expected to be reduced. The Company's ongoing liquidity requirements will be influenced by gas prices as well as by regulatory measures allowing the Company to recover increased gas costs on a timely basis and the outcome of the Company's 2001 revenue requirements applications. In addition, the Company is required to make a payment of $12 million upon the maturity of the Series 2002 Debentures in July 2002. The Company's ability to make this payment will be dependent upon the Company's cash resources, continued availability of its operating line and possible new long-term capital.

RESPONSIBILITY FOR FINANCIAL STATEMENTS

The accompanying consolidated financial statements were prepared by management of the Company in conformity with accounting principles generally accepted in Canada applied on a consistent basis. Management is responsible for the integrity and objectivity of the information contained in the consolidated financial statements. Management is also responsible for installing and maintaining appropriate internal controls, policies and procedures, which provide reasonable assurance that reliable financial information is produced and that the Company's assets are safeguarded. Ernst & Young LLP. Chartered Accountants, as the Company's external auditors appointed by the shareholders, have examined the consolidated financial statements for the years ended December 31, 2000 and 1999, in accordance with auditing standards generally accepted in Canada and rendered their independent opinion thereon. The Audit Committee of the Board of Directors meets with the external auditors to review the manner in which they are performing their responsibilities and to discuss auditing, internal accounting controls and financial reporting matters. The external auditors have full access to the Audit Committee of the Board.

AUDITORS' REPORT

To the Shareholders of Pacific Northern Gas Ltd.

We have audited the consolidated balance sheets of Pacific Northern Gas Ltd. as at December 31, 2000 and 1999 and the consolidated statements of income, retained earnings and cash flow for the years then ended. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in Canada. Those standards require that we plan and perform an audit to obtain reasonable assurance whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation.

In our opinion, these consolidated financial statements present fairly, in all material respects, the financial position of the Company as at December 31, 2000 and 1999 and the results of its operations and its cash flow for the years then ended in accordance with accounting principles generally accepted in Canada. As required by the British Columbia Company Act, we report that, in our opinion, these principles have been applied, except for the change in accounting principles for employee future benefits as explained in the summary of accounting policies to the consolidated financial statements, on a consistent basis.

Ernst & Young LLP

Chartered Accountants

Vancouver, Canada
February 13, 2001

CONSOLIDATED STATEMENTS OF INCOME

Years ended December 31	2000	($000's[1])	1999
Operating revenues *[notes 1 and 10]*	**115,733**		77,738
Cost of sales *[note 10]*	**61,750**		24,778
Operating margin	**53,983**		52,960
Operating and maintenance	**13,711**		13,478
Administrative and general	**5,617**		5,399
Amortization of deferred charges	**1,377**		867
Municipal and other taxes	**3,969**		3,999
Depreciation	**7,489**		7,227
	32,163		30,970
Operating income	**21,820**		21,990
Investment and other income	**119**		79
	21,939		22,069
Income deductions:			
Interest on long term debt	**8,015**		8,354
Other interest	**1,397**		775
	9,412		9,129
Income before income taxes	**12,527**		12,940
Income taxes *[note 3]* - currently payable	**(809)**		770
- deferred	**6,498**		5,045
	5,689		5,815
Net income for the year	**6,838**		7,125
For common shares			
Net income for the year	**6,838**		7,125
Provision for dividends on preferred shares	**338**		337
Net income applicable to common shares	**6,500**		6,788
Per common share *[note 5]*			
Basic	**1.83**		1.92
Fully diluted	**1.79**		1.87

See accompanying summary of accounting policies and notes to consolidated financial statements.

[1]*Except for per share amounts*

CONSOLIDATED BALANCE SHEETS

As at December 31	2000	($000's)	1999
ASSETS *[notes 6 and 7]*			
Current assets			
Cash	**1,385**		—
Accounts receivable *[notes 1 and 10]*	**28,178**		20,019
Gas purchase variance recoverable	**4,487**		772
Income taxes recoverable *[note 3]*	**3,566**		—
Inventories of supplies and natural gas	**2,519**		6,996
Prepaid expenses	**922**		504
	41,057		28,291
Plant, property and equipment *[note 2]*	**183,351**		182,917
Deferred charges			
Debt expense	**750**		818
Gas purchase variance recoverable	**2,701**		1,543
Pipeline rehabilitation costs	**2,201**		3,542
Other	**2,229**		1,642
	7,881		7,545
	232,289		218,753

See accompanying summary of accounting policies and notes to consolidated financial statements.

On behalf of the Board:

Roy G. Dyce
Director

Arthur H. Willms
Director

As at December 31	2000	($000's)	1999
LIABILITIES			
Current liabilities			
Bank indebtedness *[note 6]*	**24,807**		34,000
Accounts payable and accrued liabilities *[note 10]*	**30,332**		10,169
Income and other taxes payable	**2,045**		1,866
Long term debt due within one year *[note 7]*	**3,326**		3,310
	60,510		49,345
Long term debt *[note 7]*	**82,158**		85,593
Deferred income taxes	**15,653**		12,789
	158,321		147,727
Commitments and contingency *[notes 2 and 12]*			
SHAREHOLDERS' EQUITY			
Preferred shares *[note 8]*	**5,000**		6,715
Common shares *[note 9]*	**8,869**		8,839
Contributed surplus *[note 9]*	**2,158**		2,047
Retained earnings	**57,941**		53,425
	68,968		64,311
	73,968		71,026
	232,289		218,753

CONSOLIDATED STATEMENTS OF RETAINED EARNINGS

Years ended December 31	2000	($000's)	1999
Balance, beginning of year	**53,425**		50,597
Net income for the year	**6,838**		7,125
	60,263		57,722
Preferred share dividends	**338**		337
Common share dividends	**1,984**		3,960
	2,322		4,297
Balance, end of year	**57,941**		53,425

See accompanying summary of accounting policies and notes to consolidated financial statements.

CONSOLIDATED STATEMENTS OF CASH FLOW

Years ended December 31	2000	($000's)	1999
OPERATING ACTIVITIES			
Net income for the year	**6,838**		7,125
Add (deduct) items not involving cash:			
Deferred income taxes	**6,498**		5,045
Depreciation and amortization	**8,866**		8,094
Other	**(3,688)**		(3,347)
Operating cash flow	**18,514**		16,917
Non-cash working capital changes	**8,961**		(7,861)
Net cash provided by operating activities	**27,475**		9,056
INVESTING ACTIVITIES			
Additions to plant, property and equipment	**(7,869)**		(10,412)
Deferred charge expenditures	**(1,713)**		(1,960)
Net cash (used by) investing activities	**(9,582)**		(12,372)
FINANCING ACTIVITIES			
Increase (decrease) in bank indebtedness	**(9,193)**		14,453
Repayment of long term debt	**(3,419)**		(3,318)
Issue of common shares *[note 9]*	**141**		24
Redemption of junior preferred shares *[note 8]*	**(1,715)**		(3,546)
Dividends paid	**(2,322)**		(4,297)
Net cash (used by) provided by financing activities	**(16,508)**		3,316
Increase in cash during the year	**1,385**		—
Cash, beginning of year	**—**		—
Cash, end of year	**1,385**		—
Supplemental cash flow information			
Income taxes paid	**1,216**		706
Interest paid	**9,591**		9,539

See accompanying summary of accounting policies and notes to consolidated financial statements.

December 31st, 2000 and 1999

ACCOUNTING PRINCIPLES

The preparation of financial statements in conformity with generally accepted accounting principles requires management to make estimates and assumptions that affect the reported amounts of assets, liabilities, revenues, expenses and disclosure of contingent assets and liabilities. Actual results could differ from these estimates.

PRINCIPLES OF CONSOLIDATION

The consolidated financial statements include the accounts of Pacific Northern Gas Ltd. (the "Company") and its wholly-owned subsidiary, Pacific Northern Gas (N.E.) Ltd. In 1999, pursuant to regulatory approval, Centra Gas Fort St. John Inc., Peace River Transmission Company Limited with Pacific Northern Gas (N.E.) Ltd., all wholly-owned subsidiaries, were amalgamated and continued as Pacific Northern Gas (N.E.) Ltd. The amalgamation was accounted for using the continuity of interests method of accounting, under which the recorded book values of each company are aggregated together as if the companies had always been combined.

REGULATION

The Company and Pacific Northern Gas (N.E.) Ltd. are regulated utilities engaged in the transportation and distribution of natural gas. Their accounting records and practices conform to the requirements of the British Columbia Utilities Commission (the "Commission").

REVENUE RECOGNITION

Operating revenues include natural gas sales which are recorded on the basis of regular meter readings and estimates of customer usage from the last meter reading date to the end of the year. Operating revenues also include transportation services revenues which are recorded as service is provided.

The Commission approved interim rate increases, effective October 1, 2000, that are subject to final approval in conjunction with public and written hearings to be held in March 2001. The final impact, if any, of the Commission's decisions on the interim rate applications will be accounted for at the time of the decisions.

INVENTORIES OF SUPPLIES AND NATURAL GAS

Inventories of supplies and line-pack natural gas are valued at the lower of cost determined on a first-in, first-out basis and net realizable value. Inventories of natural gas in storage are valued at the lower of average cost and net realizable value.

PLANT, PROPERTY AND EQUIPMENT

Plant, property and equipment are recorded at cost less contributions in aid of construction. Cost includes an allowance for funds used during construction calculated at the Company's cost of capital. The cost of depreciable assets retired, together with removal costs, less salvage is charged to accumulated depreciation. Gains or losses on disposal are not taken into income unless the disposal is outside the normal course of business or involves a major item of plant.

Depreciation is provided on a straight-line basis for plant in service at the commencement of each fiscal year at rates prescribed by the Commission. Average annual depreciation rates are 2.8% (1999 - 2.8%) for transmission plant, 2.6% (1999 - 2.6%) for distribution plant, 5.2% (1999 - 5.4%) for general plant and 4.8% (1999 - 5.1%) for processing plant. Application of these rates for the year ended December 31, 2000 resulted in a composite rate of 2.9% (1999 - 2.9%).

DEFERRED CHARGES

(a) Debt expense

Debt expense comprises issue costs of long term debt which are amortized on a straight-line basis over the term of the related issue.

(b) Gas purchase variance recoverable

Gas purchase variance costs are being charged to cost of sales on a straight-line basis over periods ranging from one to three years. The amount of such charges to cost of sales in 2000 was $1,426,000 (1999 - $7,000).

(c) Pipeline rehabilitation costs

Pipeline rehabilitation costs are being amortized on a straight-line basis over ten years. The amount of such amortization in 2000 was $967,000 (1999 - $605,200).

(d) Other

Costs as required or permitted by the Commission have been deferred to be recovered from future revenues. During 2000, $265,000 was charged to income (1999 - $261,200 charged to income) in respect of these deferred costs. Certain regulatory deferrals, including reorganization costs in the amount of $491,000, net of income taxes, are subject to future decisions by the Commission who will determine the treatment to be given the various items.

In March 1997, an industrial customer, Skeena Cellulose Inc., obtained protection from creditors under the Companies' Creditors Arrangement

Act. The Commission authorized the Company to record losses arising in both 1997 and 1998 from this event as deferred charges. At December 31, 2000, the deferred charges amounted to $92,700 (1999 - $454,900), net of income taxes and amortization. The deferred charges arising in 1997 are being amortized on a straight-line basis over three years commencing January 1, 1998. The deferred charges arising in 1998 are being amortized on a straight-line basis over three years commencing January 1, 1999.

INCOME TAXES

The Company provides for income taxes using the income taxes currently payable method as directed by the Commission, except as described below. Under the income taxes currently payable method, no provisions are made for income taxes deferred as a result of differences in timing between the treatment for income tax and accounting purposes of various income and expenditure items.

The Commission has directed that the deferral method of accounting for income taxes be followed for certain transactions within the Company. Under the deferral method of accounting for income taxes, reported earnings are charged with the income taxes related to those earnings. Differences between these taxes and taxes currently payable, arising mainly from differences in the timing of expense deductions, are recorded as deferred income taxes.

From July 1, 1978 until its suspension on November 1, 1986, the deferral method was followed by the Company. Had the liability methodology been followed continuously since the inception of the Company, deferred income taxes recorded in the accounts would have been increased by approximately $15,679,000 (1999 - $15,263,000).

EMPLOYEE BENEFIT PLANS

Effective January 1, 2000, the Company adopted, on a prospective basis, the new recommendations of the CICA with respect to accounting for employee future benefits. The new recommendations modify the previous CICA requirements for pension costs and obligations under the Company's defined benefit pension plan and post-retirement arrangements. The Company will continue to use the pay-as-you-go method of accounting for non-pension benefits as directed by the Commission. The effect of adopting the new recommendations was to decrease 2000 pre-tax income by approximately $17,000.

Under the new recommendations, the Company accrues its obligations under employee benefit plans and the related costs, net of plan assets. The plan assets are valued at fair value and obligations are now discounted using a current market interest rate.

Past service costs from plan amendments are amortized on a straight-line basis over the average remaining service period of employees active at the date of amendment.

The average remaining service period of the active employees covered by the pension plan is 13 years. The average remaining service period of the active employees covered by the other retirement benefits plan is 17 years.

For the defined contribution plan maintained by the Company, contributions payable by the Company are expensed as pension costs.

STOCK BASED COMPENSATION PLAN

The Company has one stock-based compensation plan, which is described in Note 9. No compensation expense is recognized for this plan when the stock options are issued to employees. Any consideration paid by employees on exercise of stock options is credited to share capital and contributed surplus.

FINANCIAL INSTRUMENTS

Derivative and other financial instruments are utilized in connection with management of gas supply and interest rates. The Company enters into forward, future, swap and option contracts to manage the impact of market fluctuations on assets, liabilities, or other contractual commitments. The Company defers the impact of changes in the market value of these contracts until such time as the associated transaction is completed.

Credit risk is the risk of loss from non-performance of suppliers, customers or financial counterparties to a contract. The Company maintains credit policies which management believes significantly minimize overall credit risk. These policies include a review of a counterparty's financial condition, measurement of credit exposure and monitoring of concentration of exposure to any one customer or counterparty.

COMPARATIVE FIGURES

Certain of the prior year figures have been restated to conform with current year's presentation.

December 31st, 2000 and 1999

1. MAJOR CUSTOMERS

The proportion of energy deliveries and operating revenues attributable to large industrial customers is as follows:

	2000		1999	
Percent	Energy	Operating Revenues	Energy	Operating Revenues
Methanex Corporation	**43**	**19**	58	27
Skeena Cellulose Inc., Eurocan Pulp and Paper Co. and Alcan Smelters and Chemicals Ltd. and B.C. Hydro and Power Authority	**24**	**12**	16	11

At December 31, 2000, 14% (1999 - 13%) of accounts receivable was attributable to these five customers.

2. PLANT, PROPERTY AND EQUIPMENT

($000's)	2000	1999
Transmission plant	**173,313**	169,377
Distribution plant	**72,899**	70,864
General plant	**17,885**	17,075
Processing plant	**2,730**	2,642
Construction in progress	**1,335**	151
Total plant, property and equipment	**268,162**	260,109
Accumulated depreciation		
Transmission plant	**55,779**	51,014
Distribution plant	**19,502**	17,650
General plant	**7,527**	6,647
Processing plant	**2,003**	1,881
Total accumulated depreciation	**84,811**	77,192
	183,351	182,917

During the year, the Company received contributions in aid of construction of $309,000 (1999 - $178,000) which have been recorded as a reduction of distribution plant.

The Quintette mine at Tumbler Ridge was closed in August 2000. Under its current contract, Quintette Coal Limited ("Quintette") is required to notify the Company twelve months in advance of termination of gas distribution service. At this time, notice has not yet been given and Quintette continues to receive service and make monthly payments in accordance with the contract terms. Quintette is also required to reimburse the Company for the undepreciated cost of the assets purchased to service the facility. The Company expects to receive $270,000 as a termination payment under these contract terms which is approximately equal to the net book value of the Quintette assets at December 31, 2000. It is anticipated that the Quintette mine will require natural gas deliveries for several more years until the reclamation process is completed. It is not clear what future impact the mine closure will have on the number of customers located in the area. Approximately $1.3 million of the Company's plant, property and equipment is used to service the Tumbler Ridge area. The net book value of these assets at December 31, 2000 is $700,000.

On May 24, 2000, Methanex Corporation ("Methanex") announced the temporary closure of its Kitimat methanol plant for a period of twelve months, effective July 1, 2000. Approximately $37.3 million of the Company's net book value of plant, property and equipment and $6.1 million of unrecorded deferred income taxes were incurred to service the Methanex contracts. The revenue from these contracts, expiring between 2002 and 2009, may not be sufficient to recover the costs incurred.

It is not possible to determine at this time whether a write down of the Company's assets will be required. The outcomes are dependent upon a number of factors, including the results of regulatory rate hearings to be held in March 2001, the future prices of natural gas, the development of satisfactory arrangements for cost and financial restructuring with the provincial government through the B.C. Job Protection Commissioner under an agreement in principle between the Company and Methanex dated October 5, 2000, and the results of the Company's expenditure containment measures and business expansion activities.

3. INCOME TAXES

Deferred income taxes reflect the net tax effects of temporary differences between the carrying amounts of assets and liabilities for financial reporting purposes and the amounts used for income tax purposes. Significant components of the Company's deferred tax liabilities and assets are as follows:

December 31	2000	($000's) 1999
Deferred tax liabilities		
Capital cost allowance claimed for income tax purposes in excess of depreciation and amortization	**14,462**	14,462
Other – net	**1,191**	576
Net deferred tax liabilities	**15,653**	15,038
Deferred tax assets		
Loss carryforwards	–	2,249
Net deferred tax assets	–	2,249

Income tax expense varies from the amount that would be expected if current rates were applied to income before income taxes for the following reasons:

	2000	1999
Combined Canadian federal and provincial statutory income tax rates, including surtaxes (percent)	**45.6**	45.6
Increase (decrease) in income taxes resulting from:		
Benefit realized upon application of loss carryforwards	**(1.8)**	(2.2)
Large corporations tax	**4.2**	3.5
Depreciation in excess of capital cost allowance	**2.4**	2.4
Deferred charge expenditures deducted for tax purposes	**(5.8)**	(4.9)
Other items	**.8**	.5
Effective rate of income taxes (percent)	**45.4**	44.9

4. PENSION PLANS

The Company, and its subsidiary have defined benefit pension plans, defined contribution pension plans and defined benefit plans providing retirement and post-employment health and life insurance benefits for most employees.

Information about benefit plans is as follows:

($000's)	2000
Accrued benefit obligations	
Balance, beginning of year	12,192
Current service cost	549
Interest cost	860
Benefits paid	(375)
Actuarial gains (losses)	—
Balance, end of year	13,226
Plan assets	
Fair value, beginning of year	12,204
Actual return on plan assets	921
Employer contributions	504
Employees' contributions	20
Benefits paid	(375)
Actuarial gains	1,388
Fair value, end of year	14,662
Funded status – plan surplus	1,436
Unamortized net actuarial gains	(1,388)
Unamortized past service costs	—
Unamortized transitional obligation	(18)
Accrued benefit assets	30
Valuation allowance	—
Accrued benefit asset, net of valuation allowance	30

The following is a summary of the significant actuarial assumptions used in measuring the Company's accrued benefit obligations:

	2000
Discount rate	7.00%
Expected long-term rate of return on plan assets	7.50%
Rate of compensation increase	3.25%

In addition, in determining the expected cost of healthcare benefit plans, it assumed that the health care costs will decrease gradually to 5% in 2003 and remain level thereafter.

The Company's net benefit plan expense is as follows:

($000's)	2000
Current service cost	536
Interest cost	860
Expected return on plan assets	(921)
Amortization of past service costs	—
Amortization of net actuarial gain (loss)	—
Amortization of transitional obligation	2
Valuation allowance provided against accrued benefit asset	—
Net benefit plan expense	477

The pension expense for the year ended December 31, 2000 and 1999 was $535,000 and $491,000, respectively.

Payments made during the year for non-pension benefits, which are accounted for on a pay-as-you-go basis, were $61,000. Had the accrual methodology been followed for non-pension benefits, pension expense would have increased by $328,000.

5. EARNINGS PER COMMON SHARE

Earnings per common share have been calculated after deducting preferred share dividend requirements from net income. The weighted average number of common shares outstanding for the year ended December 31, 2000 is 3,544,242 (1999 - 3,515,457). Earnings per share on a fully diluted basis were calculated after allowing for the exercise of employees' options on Class A common shares.

Net income used in determining fully diluted earnings per common share has been increased by $82,000 in 2000 (1999 - $71,000) to give effect to an imputed after tax return of 3.1% (1999 - 2.5%) on funds which would have been available on the exercise of options.

6. BANK INDEBTEDNESS

	2000	($000's)	1999
Outstanding cheques less cash balances on hand	—		8,500
Bank demand operating line of credit	**24,807**		25,500
	24,807		34,000

The Company has a bank demand operating line of credit of $30 million which bears interest at bankers acceptance rates (December 31, 2000 - 7.74%; December 31, 1999 - 5.1%). On January 26, 2001, the line of credit was secured by the pledge of a $30 million debenture, and a charge on certain accounts receivable and inventories, pursuant to a previous agreement between the Company and the operating lender *(see note 7).*

7. LONG TERM DEBT

	2000	($000's)	1999
Secured Debentures (a)			
2002 Series, 10.85% due July 15, 2002, payable in annual instalments of $2,000,000, with a final instalment of $12,000,000 at maturity.	**14,000**		16,000
2011 Series, 10.75% due December 13, 2011, payable in annual instalments of $700,000 and $800,000 in each of years 2009 and 2010 with a final instalment of $5,000,000 at maturity.	**12,200**		12,900
2018 Series, 8.75% due November 15, 2018, payable in annual instalments of $600,000, commencing November 15, 1999 and $1,000,000 in each of the years 2014 to 2017, with a final instalment of $7,000,000 at maturity.	**18,800**		19,400

7. LONG TERM DEBT *(continued)*

	2000	($000's)	1999
2025 Series, 9.30% due July 18, 2025, payable in annual instalments of $500,000, commencing July 18, 2004 with a final instalment of $9,500,000 at maturity.	**20,000**		20,000
2027 Series, 6.90% due December 2, 2027, payable in annual instalments of $500,000, commencing December 2, 2006 with a final instalment of $9,500,000 at maturity.	**20,000**		20,000
Construction advances and other (b)	**484**		603
	85,484		88,903
Long term debt due within one year	**3,326**		3,310
	82,158		85,593

(a) Collateral for the Secured Debentures consists of a specific first mortgage on substantially all of the Company's fixed assets and gas purchases and gas sales contracts, and a first floating charge on other property, assets and undertakings.

(b) Advances have been received from certain industrial concerns to enable construction of the facilities required to provide natural gas service. This financing is non-interest bearing and will be repaid as these customers meet their commitments for the purchase of natural gas.

(c) Payments required to meet sinking fund and retirement provisions during the next five years are as follows:

	($000's)
2001	3,326
2002	13,300
2003	1,300
2004	1,800
2005	1,800

8. PREFERRED SHARES

		2000	($000's) 1999
Authorized			
1,400,000	cumulative redeemable junior preferred shares with a par value of $10		
200,000	6.75% cumulative redeemable preferred shares with a par value of $25 each		
Issued			
200,000	6.75% preferred shares	**5,000**	5,000
Nil	junior preferred shares (1999 - 171,573)	—	1,715
		5,000	6,715

During 2000, the Company redeemed 171,573 (1999 - 354,591) junior preferred shares for cash consideration of $1,715,730 (1999 - $3,545,910). The junior preferred shares were redeemable on a quarterly basis in amounts equal to 90% of the tax savings realized from the utilization of the non-capital loss carryforwards arising from the acquisition in 1996 of all of the outstanding shares of Centra Gas Victoria Inc., a company related through common control.

The 6.75% preferred shares are redeemable at the option of the Company at $26 per share plus any accrued and unpaid dividends at the date of redemption.

9. COMMON SHARES

		2000	($000's) 1999
Authorized			
6,000,000	Class A non-voting common shares with a par value of $2.50 each		
20,000	Class B voting common shares with a par value of $2.50 each		
Issued			
3,527,780	Class A common shares (1999 - 3,515,660)	**8,819**	8,789
20,000	Class B common shares	**50**	50
		8,869	8,839

The Company has a stock option incentive plan under which share options are granted to certain of its employees. Share options are granted at an exercise price equal to the fair market value of the Company's common shares on the date of the grant.

Share options vest in five equal stages with the first stage vesting on the date of the grant, and the remainder in four equal annual stages commencing on the first anniversary of the date of the grant. The maximum term of options awarded is ten years.

As of December 31, 2000, 217,600 shares are reserved for issuance pursuant to options that may be granted under the stock option incentive plan.

During 2000, the Company issued 12,120 (1999 - 1,200) Class A common shares for cash consideration of $141,000 (1999 - $24,000) upon the exercise of employee options. Of this amount, $111,000 (1999 - $21,000) representing the excess of the issue price over the par value of the shares has been credited to contributed surplus.

A summary of the status of the Company's stock option plan as of December 31, 2000 and 1999, and changes during the years ending on those dates is presented below:

	2000		1999	
	Number of shares	Weighted-Average Exercise price	Number of shares	Weighted-Average Exercise price
Outstanding at beginning of year	131,000	$ 20.91	111,900	$ 19.86
Granted	28,900	15.50	20,300	24.50
Exercised	(12,120)	11.69	(1,200)	20.00
Forfeited	(15,420)	23.77	—	
Outstanding at end of year	132,360	20.24	131,000	20.91
Options exercisable at end of year	93,160	20.27	94,000	19.26
Weighted average remaining contractual life	6.4 years		6.3 years	

	Options Outstanding		Options Exercisable	
Expiry Date	Number of shares	Exercise price	Number of shares	Exercise price
January 28, 2002	5,880	$ 14.125	5,880	$ 14.125
May 4, 2003	6,200	15.750	6,200	15.750
November 7, 2005	28,300	20.000	28,300	20.000
March 14, 2006	18,100	18.750	18,100	18.750
March 14, 2007	17,100	20.750	14,040	20.750
March 24, 2008	14,360	30.500	8,880	30.500
March 11, 2009	15,820	24.500	6,440	24.500
March 16, 2010	26,600	15.500	5,320	15.500
	132,360		93,160	

10. RELATED PARTY TRANSACTIONS

The Company's transactions with related parties are as follows:

($000's)	2000	1999
Westcoast Energy Inc., parent company		
Transportation services	**839**	836
Materials and services	**782**	919
Centra Gas British Columbia Inc., a company related through common control		
Materials and services	**24**	88
Enlogix CIS L.P., a company related through common control		
Services	**582**	331
Engage Energy Canada, L.P., an entity related through common control		
Natural gas purchases and services	**84**	642
Natural gas sales	**7,708**	—

Accounts payable and accrued liabilities as at December 31, 2000 include $171,000 (1999 - $1,681,000) and accounts receivable at December 31, 2000 include $5,241,000 (1999 - $nil) in respect of the above related party transactions.

These transactions are in the normal course of operations and are recorded at amounts established and agreed between the related parties.

11. FAIR VALUES OF FINANCIAL INSTRUMENTS

The fair values of debt instruments included in the consolidated balance sheets are as follows:

	Carrying value		Fair value	
($000's)	**2000**	1999	**2000**	1999
Long term debt	**85,484**	88,903	**77,204**	97,058

The fair values of the Company's long term debt are estimated by reference to quoted market prices for actual or similar instruments.

The fair values of other financial instruments included in the consolidated balance sheets, including accounts receivable, gas purchase variance recoverable, income tax recoverable, bank indebtedness, income and other taxes payable, and accounts payable and accrued liabilities approximate their carrying values.

12. NATURAL GAS AND INTEREST RATE CONTRACTS

The Company's tolls are set using a forecasted price for gas. However, the Company's gas supply contracts contain pricing mechanisms that reflect monthly variations in the price of gas, rather than fixed prices. At December 31, 2000, the Company has entered into natural gas price swap contracts to effectively fix the price for approximately 4.63 billion cubic feet or 45% of its forecast 2001 system gas supply (7.5% at December 31, 1999). In addition to the above mentioned swap contracts, at December 31, 1999 the Company had also entered into natural gas price collar contracts to provide a ceiling and floor price for approximately 0.55 billion cubic feet or 5.1% of its forecast 2000 system gas supply. The difference between the price of gas used for toll purposes and the actual cost of gas purchased is deferred and refunded to or recovered from customers as directed by the Commission. The swap contracts have a fair value of $18,960,000 receivable at December 31, 2000 ($730,791 payable at December 31, 1999). The collar contracts had a fair value of $366,977 payable at December 31, 1999. The fair values reflect the estimated amounts that the Company would receive at December 31, 2000 (pay at December 31, 1999) to terminate the swap contracts, based on the estimated future net cash flows under the terms of each contract.

Tolls for customers of Pacific Northern Gas (N.E.) Ltd. are predicated on $8,000,000 of long-term debt financing. Accordingly, the Company is party to an interest rate swap contract that converts the interest rate characteristics of $8,000,000 of short-term borrowings from floating to a fixed rate of 7.7% until October 2004. The swap contract has a fair value of $555,000 payable at December 31, 2000 ($411,000 payable at December 31, 1999). The fair value represents the amount the Company would have to pay to terminate the swap contract at December 31, 2000, based on the quoted market prices for similar instruments.

These estimated fair market values have no impact on earnings (see also note 11) due to the regulated nature of the Company's operations. Based on the current regulatory process, any gains or losses arising from utility related financial instruments would be treated as part of the cost of service.

(Dollar amounts are in thousands except for per share and per GJ figures)

For the year ended December 31	2000	1999	1998	1997
DELIVERIES (TJ)*				
Residential	**4 216**	4 202	3 688	3 796
Commercial	**3 543**	3,108	2 897	3 162
Small Industrial	**3 875**	3 694	3 704	2 972
Large Industrial	**23 137**	31 573	28 498	32 365
Total energy delivered	**34 771**	42 577	38 787	42 295
Customers at year-end	**39,665**	39,238	38,808	37,669
Average rates per GJ*				
Residential	**$ 8.20**	6.16	5.80	5.68
Commercial	**5.96**	4.84	4.41	4.41
REVENUE				
Residential	**$ 34,557**	25,881	21,380	21,552
Commercial	**21,115**	15,036	12,763	13,952
Small industrial	**9,349**	6,356	4.912	4,848
Large industrial	**36,108**	29,967	31,883	35,166
Off-System	**14,108**	–	754	1,804
Other	**496**	498	452	539
	$ 115,733	77,738	72,144	77,861
EXPENSES				
Cost of sales	**$ 61,750**	24,778	20,887	27,295
Operating	**23,243**	22,876	20,615	19,877
Interest	**9,347**	9,050	9,307	8,903
Depreciation & amortization	**8,866**	8,094	8,322	7,067
Income taxes	**5,689**	5,815	6,559	6,793
	$ 108,895	70,613	65,690	69,935
NET INCOME	**$ 6,838**	7,125	6,454	7,926
PER COMMON SHARE				
Earnings	**$ 1.83**	1.92	1.73	2.16
Dividends	**0.56**	1.12	1.10	1.00
CAPITALIZATION				
Long-term debt	**$ 82,158**	85,593	88,894	92,135
Deferred income taxes	**15,653**	12,789	11,126	7,119
Preferred shares	**5,000**	6,715	10,261	13,609
Common equity	**57,941**	64,311	61,459	59,142
Total capitalization	**$ 160,752**	169,408	171,740	172,005
Utility plant				
In service (net)	**$ 182,016**	182,766	178,614	176,103
Construction in progress	**1,335**	151	1,610	1,459
Total investment in utility plant	**$ 183,351**	182,917	180,224	177,562

1996	1995	1994	1993	1992	1991
3 056	2 644	2 580	2 336	1 510	1 517
2 259	2 217	2 183	2 102	1 420	1 484
2 120	1 905	1 924	1 984	1 574	1 518
30 981	27 890	31 339	31 084	29 592	30 734
38 716	34 656	38 026	37 506	34 096	35 253
27,978	26,638	25,714	24,667	17,282	16,042
4.90	5.30	5.31	5.03	5.15	4.83
3.58	4.58	4.65	4.36	4.54	4.33
14,971	14,026	13,708	11,740	7,770	7,321
9,157	10,161	10,148	9,158	6,443	6,427
3,354	4,013	3,903	3,665	2,486	3,048
33,842	30,237	34,125	32,566	32,364	51,202
1,068	2,119	–	–	–	–
431	442	442	345	246	299
62,823	60,998	62,326	57,474	49,309	68,297
14,975	19,943	22,281	20,390	17,302	35,886
16,611	16,518	16,527	16,143	13,096	12,037
8,822	8,915	7,918	7,781	7,504	7,523
6,792	5,646	4,969	4,420	4,136	3,805
8,238	3,785	4,030	2,777	1,868	3,078
55,438	54,807	55,725	51,511	43,906	62,329
7,385	6,191	6,601	5,963	5,403	5,968
2.01	1.67	1.80	1.63	1.48	1.67
0.96	0.94	0.88	0.88	0.80	0.78
74,862	80,056	63,990	67,937	51,875	55,817
1,863	15,514	15,731	15,703	14,877	14,919
18,910	5,000	5,000	5,000	5,000	5,000
54,785	51,038	48,432	44,787	42,020	39,357
150,420	151,608	133,153	133,427	113,772	115,093
156,995	154,421	145,047	135,187	122,999	118,808
1,244	1,929	2,590	1,789	1,028	1,553
158,239	156,350	147,637	136,976	124,027	120,361

The bylaws of the Toronto Stock Exchange ("TSE") require that the Company disclose the corporate governance practices of its Board of Directors ("Board"). The following report addresses the principal responsibilities of a board of directors contained in the guidelines for corporate governance established by the TSE.

Through its Corporate Governance Committee (the "Committee"), the Board develops sound corporate governance practices to enhance corporate performance.

BOARD OF DIRECTORS

The Board, as set out in its terms of reference, has the responsibility for overseeing the conduct of the business of the Company and the activities of management which is responsible for the day to day operations of the business.

COMPOSITION OF THE BOARD

The Board is composed of nine directors. One of the directors is a full-time officer of the Company, two are full-time officers of Westcoast Energy Inc. ("Westcoast"), which owns 100% of the voting common shares and is therefore considered a significant shareholder, and one recently retired as the President and Chief Operating Officer of Westcoast and continues to provide consulting services to Westcoast. The TSE Guidelines provide that a director related to a significant shareholder should not be considered a related director of the subsidiary company. The remaining five directors do not have interests in or relationships with the Company or its parent (other than interests and relationships arising from shareholdings) which could, or could reasonably be perceived to materially interfere with such directors' ability to act with a view to the best interests of the Company. The Board has concluded that a majority of the directors of the Company are outside and unrelated.

COMMITTEES OF THE BOARD

The Board has established and adopted terms of reference for each of the Audit, Executive, Environment, Health and Safety, Compensation and Corporate Governance Committees.

The *Audit Committee* is composed of unrelated directors, of whom a majority including the Chair are outside directors and a majority are financial professionals. One of the three committee members is a full-time officer of Westcoast. This committee is broadly responsible for ensuring that the Company's management has designed and implemented an effective system of internal financial controls, for reviewing and reporting on the integrity of the consolidated financial statements of the Company, for ensuring compliance with regulatory and statutory requirements as they relate to financial statements, taxation matters and the disclosure of material facts and for reviewing the appropriateness and effectiveness of the Company's policies and business practices which impact on the financial integrity of the Company, including those relating to internal auditing, insurance, accounting, information services and systems and financial controls, management reporting and risk management.

The *Executive Committee* is narrowly mandated to act as the approving body for expenditures which have been broadly approved by the Board and which are beyond the approval levels of the President and Chief Executive Officer and to perform such functions and exercise such powers specifically delegated to the committee by the Board. It is composed of three directors, one of whom is a full-time officer of the Company and another who provides consulting services to Westcoast. The Board has determined that a majority of the committee members is unrelated.

The *Environment, Health and Safety Committee*, previously the Environment Committee, is composed of three directors, one of whom is a full-time officer of the Company. A majority of the committee members are outside and unrelated. This committee is responsible for reviewing and monitoring the policies and activities of the Company relating to environment, health and safety matters on behalf of the Board.

The *Compensation Committee* is composed of directors who are unrelated. One of the three members is a full-time officer of Westcoast. This committee is generally responsible for recommending to the Board human resources and compensation policies and guidelines for application to the Company and for implementing and overseeing human resources and compensation policies approved by the Board. In addition, it is responsible for periodically reviewing the adequacy and form of the compensation of directors and for ensuring that the compensation realistically reflects the responsibilities and risks involved in being an effective director of the Company and for reporting and making recommendations to the Board accordingly.

The *Corporate Governance Committee* is composed of unrelated directors, a majority of whom, including the Chair, are outside directors. One of the members of this committee provides consulting services to Westcoast. This committee's prime responsibility is for developing and monitoring the Company's overall approach to corporate governance issues and for administering a corporate governance system which is effective in the discharge of the Company's obligations to its shareholders. The nominating responsibility of this committee includes proposing new members to the Board, establishing criteria for Board membership, recommending composition of the Board and its committees, assessing directors' performance on an ongoing basis and developing an orientation and education program for new members of the Board.

CHAIRMAN

The Board has determined that the present Chairman of the Board is an outside and unrelated director and independent of management.

SHAREHOLDER FEEDBACK AND CONCERNS

In conjunction with the Westcoast investor relations department, the Company maintains an active shareholder relations program. The program is designed to ensure that shareholder inquiries receive a prompt response either from the investor relations department or an appropriate officer of the Company.

DECISIONS REQUIRING BOARD APPROVAL

The Board operates by seeking the advice of and delegating powers, duties and responsibilities to committees of the Board, by delegating certain of its authorities to management and by reserving certain powers to itself. In addition to those matters which must by law be approved by the Board, the Board retains the responsibility for managing its own affairs including selecting its Chair, nominating candidates for election to the Board, constituting committees of the Board and determining director compensation.

ROLE OF MANAGEMENT

Members of the management team report to the Board and its Committees on a regular basis to review the Company's financial and operational results and the Company's progress in fulfilling its strategic goals and objectives. The Board develops processes for defining its expectations of management such as reviews of the Company's strategic plan with management and a comprehensive review of the performance of the President and Chief Executive Officer, which review is carried out by the Compensation Committee.

CONCLUDING STATEMENT

The Company has adopted the recommendations for improved corporate governance established by the TSE.

CORPORATE INFORMATION

Directors

Robert F. Chase [1, 5]
President and Chief Executive Officer
Lexacal Investment Corp.
Vancouver, British Columbia

Roy G. Dyce [3, 4]
President and Chief Executive Officer
Pacific Northern Gas Ltd.
Vancouver, British Columbia

Roy Illing [2]
President
Roy Illing Consultants Limited
Calgary, Alberta

Hugh C. Morris [1, 2, 3]
Chairman
Eldorado Gold Corporation
Vancouver, British Columbia

Robert F. O'Shaughnessy [3]
Company Director
Galiano Island, British Columbia

Kenneth E. Rekrutiak [2]
Senior Vice President and
Chief Information Officer
Westcoast Energy Inc.
Vancouver, British Columbia

Richard D. Walker [4, 5]
Company Director
Vancouver, British Columbia

Arthur H. Willms [4, 5]
Director of Westcoast Energy Inc.
Vancouver, British Columbia

Eric L. Schwitzer [1]
Senior Vice President, Strategic Development
Westcoast Energy Inc.
Vancouver, British Columbia

1 Audit Committee
2 Compensation Committee
3 Environment, Health and Safety Committee
4 Executive Committee
5 Corporate Governance Committee

Officers

A.H. Willms
Chairman of the Board

R. G. Dyce
President and Chief Executive Officer

G. B. Weeres
Vice President,
Operations and Engineering

J.M. McLeod
Treasurer

E.A. Fletcher
Comptroller

D.G. Unruh
Secretary

K. Stark-Anderson
Assistant Secretary

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Registrar and Transfer Agent

Computershare Trust Company
of Canada
Vancouver, Calgary,
Regina, Winnipeg,
Toronto, Montreal

Auditors

Ernst & Young LLP
Vancouver BC

Annual Meeting

The Annual Meeting of the Shareholders of Pacific Northern Gas Ltd. will be held in the Grouse Room at the Hyatt Regency Hotel, Vancouver, British Columbia on Thursday, April 19, 2001 at 10:00 am (Local Time).

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CANADA V6E 4E6

Printed in Canada